Government of Alberta ■

Petroleum Plaza – North Tower
9945 – 108 Street
Edmonton, Alberta T5K 2G6
Canada
www.alberta.ca

GAS ROYALTY OPERATIONS INFORMATION BULLETIN June 2010

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PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for April 2010, refer to Attachments 1, 1A, 2, 2A and 3. These attachments are also available in Excel Format.

B. NOTICES

2010 Capital Cost, Operating Cost and Custom Processing Fee Allowances

For the January through March 2010 billing period invoices, royalty clients received estimated monthly cost deductions that were based on actual allowable costs for the 2008 production year, multiplied by their estimated Facility Effective Royalty Rates (FERR), divided by 12 (months).

The information in the 2009 AC2, AC3, and AC5 documents were used to calculate the 2009 actual capital cost, operating cost and custom processing fee allowances. The calculations are reflected in the April 2010 Initial Annual Billing Period (IABP) invoice, issued in June 2010.

The 2009 actual allowable costs will become the royalty client's 2010 allowable cost estimates.

Commencing with the April 2010 billing period, royalty clients will receive monthly deductions based on their 2010 allowable cost estimates, multiplied by their new FERR, minus the total deductions received in the January through March 2010 billing period invoices, divided by the number of months remaining in the year (e.g. 9 months as of the April billing period).

If a royalty client requires a change to the 2010 go-forward allowable cost estimates and/or the FERR, a written request with supporting documentation must be submitted to the Gas Royalty Client Services (see Chapter 6, Section 1 of the Guidelines). These estimates must be calculated and submitted at a client/facility level.

C. MONTHLY INFORMATION

April 2010 Royalty Due July 31

- **Royalty clients are to remit the total amount payable shown on the July 2010 Statement of Account by July 31, 2010.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date.

Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The July 2010 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your April 2010 invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of April 2010 if it is paid in full by July 31, 2010.

- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

  Note: If the due date falls on a non-business day, the next business day will apply as the due date.

- Cheques are payable to the Minister of Finance, Province of Alberta.

May 2010 VA4 Due July 15

The VA4 forms for the production month of May 2010 are due in the department offices by July 15, 2010.

Note: If the due date falls on a non-business day, the next business day will apply as the due date for VA4 forms.

Registry Deadline Submissions

The Registry deadline submissions for SAF, OAF, and Volumetrics are posted in the Petroleum Registry of Alberta website "Reporting Calendars" under Calendars. Changes to this calendar will be posted on the Registry website home page in "Broadcast Messages."

Interest Rate June 2010

Alberta Energy's interest rate for June 2010 is 3.25%.

March Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the March 2010 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$2,788,450.42	($5,985,743.72)	($3,197,293.30)

March Penalty Charges

The penalty table below shows at the form level, the total penalty charges and reversals, for the March 2010 billing period:

Form	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2010/03
AC2	$46,100	($12,400)	$33,700
AC4	$1,200	($200)	$1,000
AC5	$0	$0	$0
NGL1	$0	$0	$0
VA2	$0	$0	$0
VA3	$1,000	$0	$1,000
VA4	$700	($100)	$600
Total	**$49,000**	**($12,700)**	**$36,300**

Gas Royalty Operations Support

Upon request, Gas Royalty Operations staff will be available to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to contact your respective Gas Royalty Client Services portfolio representative, as identified in Section F of this bulletin, to arrange a meeting.

Well Event Measured Depth Determination Letter

The department has issued a "Well Event Measured Depth Determination Letter" under the Report Package DOE – Gas to facility operators via the PRA on June 1 and 15, 2010. This letter shows the confirmed Measured Depth (MD) of each active well event, which will be used to calculate the Depth Factor (DF) of the quantity component rate under the new royalty formula. A well event that is not listed on the letter and does not have a confirmed MD will receive a DF of 1. When the changes to the MD are confirmed by the department, a letter is issued to a facility operator who reports changes through the PRA

to well event attributes affecting MD. All changes to the MD are applied on a go forward basis only, if a retroactive change is required, a written request must be submitted to the department. Facility operators are advised to submit well event attribute changes by the last day of the calendar month in order for timely determination of MD.

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure that the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role, then that BA can receive SAF/OAF allocations from the WIO role start date forward.
- If a BA has a WIO role with an end date, then they can only receive SAF/OAF allocations from the WIO role start date until the end date. Any SAF/OAF allocations after the end date will be rejected.
- If a BA does not have a WIO role start date, then that BA cannot receive SAF/OAF allocations.

Please contact Client Registry at 780-422-1395 if you have any questions regarding the information supplied on this listing.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at 780-422-1395.

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Royalty Deposit Adjustment

The annual royalty deposit adjustment is calculated as 1/6th of the client's previous year's royalty multiplied by a factor. The factor of 1.51 is calculated by dividing the current year's long term gas price for 2010 of $5.50 by the average 2009 Alberta reference price of $3.65. The adjustment has been processed in the Initial Annual Billing Period (IABP), June 2010 calendar month (April 2010 billing period invoice). If you have any questions, please contact Penny White at 780-422-8083.

Reporting Reminder - Stream Allocation Factor (SAF)/Owner Allocation Factor (OAF)

Volumes must be reported at the well event level to receive exemption credits for;

- Deep Gas Royalty Holiday Program (DGRHP)
- Natural Gas Deep Drilling Program (NGDDP)
- New Well Royalty Reduction (NWRR) program

No royalty exemptions will be given for the well if reporting is at the higher level (unit, well group, etc.). Once a well is no longer part of a royalty program, reporting must be submitted at the highest level otherwise rejections will result in the SAF/OAF and outstanding volumes will be subject to provisional assessment, where applicable. Should you have any questions, please contact Joyce Chen at 780-427-1550.

Royalty Liable Gas Used for Fuel (PURREC/PURDISP)

The department is still reviewing volumetric dispositions of gas, reported on the Petroleum Registry of Alberta (PRA), from batteries, gathering systems or gas plants to batteries or gathering systems for the purpose of gas sold and used for fuel. This review is for the production years 2005 onwards and production year 2005 is to be completed in 2010. The objective of the review is to ensure that all gas sold and used for fuel is accurately reported on the PRA to facilitate Crown royalty calculation. Effective June 4, 2009, when there is a sale of gas or transfer of ownership within the royalty network, the selling facility is required to report PURDISP, which would then auto populate the PURREC for the purchaser (receiving facility). This enhances the controls to prevent

fuel sale gas volumes from being incorrectly reported in PRA. This new reporting method also applies to all prior period amendments completed after June 4, 2009.

A purchase disposition (PURDISP) is a volume of product that has been sold by a facility to another facility within the royalty network. A PURDISP of gas is subject to Crown royalty charges. For example, effective June 4, 2009, if a Gas Plant (GP) sells gas for fuel to a Battery (BT) each month, the reporting is:

1. The GP operator must report a PURDISP.
2. This will auto populate a PURREC at the BT.
3. The GP operator must then file a SAF/OAF for the PURDISP.

All parties should take steps to ensure that in network sales or transfers of gas are correctly reported in the PRA. This is applicable for year 2005 to current.

PLEASE NOTE:

- The industry is urged to be proactive in reporting correctly all gas that is sold for fuel from 2006 onwards rather than having to wait until being informed by the Department.
- It has been noticed that there are situations where fuel activity is not reported for some months in the year and yet for other months it is reported on the PRA volumetric forms. Kindly review such inconsistencies and report fuel activity for the missing months, from 2006 onwards, if applicable.
- Gas that is used for fuel at the oil sands site is royalty waived only if the gas is produced from the same lease as the oil sands lease. Please Refer to Section 13(1) of the Natural Gas Royalty Regulation, 2009.
- Before submitting amendments for a closed out year, please advise the department so that the MRIS system could be opened to accept these amendments. This will avoid re-submitting them later.

Annual Operating Cost Adjustment for 2004 Through 2008 Production Years

Royalty Clients may have had a charge type on their February 2010 invoice titled "Annual Operating Cost Adjustment". This adjustment represents the difference between the actual annual operating costs and the accumulated estimated monthly unit operating cost rate (UOCR) deductions, including any prior annual adjustments, for the 2004 through 2008 production years. Two reports titled Annual Operating Cost Adjustment Details and Annual Operating Cost Adjustment Summary were included in the February invoice issued in April. Each prior year's actual rates from this year's UOCR calculation process are published and can be viewed at the **Unit Operating Cost Rates** link on the Royalty Related Information page on the department website.

Effective with the 2009 production year, operating costs are distributed to owners of each facility in a similar manner as capital costs and custom processing fees. This new method of distribution does not require an estimated or actual UOCR and there is no subsequent need to recapture operating costs from non-owners at the end of the year.

For additional information, please refer to the April 2004 Supplement Information Bulletin 04-03A as well as the Changes to Gas Cost Allowance link on the department website. If you require further information on these changes, please contact your respective Gas Royalty Client Services portfolio representative as identified in Section F.

Alberta Royalty Framework Gas Cost Allowance (GCA) Allocation Edits

Under the Alberta Royalty Framework rules and edits, a cost allocation to another facility is only allowed if there is a physical flow of volumes between the facilities. Depending on the reporting situation, operators have several options to align costs with the volumes that incur those costs:

1. If there are no longer any volumes at the reporting facility, discontinue reporting at that facility and commence reporting at the allocation facility
2. If there are volumes at both facilities, transfer a portion of the reporting facility's costs and commence separate reporting at each facility
3. If both facilities receive volumes from a common upstream facility, discontinue reporting downstream and commence reporting upstream
4. If a common upstream facility is a battery, transfer a portion of the reporting facility's costs and commence separate reporting at each facility

However, recognizing the administrative effort required in aligning costs with volumes, the department, following discussions with CAPP and SEPAC, proposes a temporary (one year) solution by treating specific reporting situations as exceptions. For the 2009 production year's annual cost reporting, the volume edit remains in place while industry operators initially file Allowable Cost (AC) forms by the legislated due date. The volume edit would identify and reject allocations where a physical flow of volumes is not evident. Industry would have to apply for an exception by submitting a written request identifying the rejected allocations, allowing sufficient time for the department to manually review and approve these situations. Once approved, the re-submitted AC forms are required prior to the cut-off date of June 15th, 2010, in order to apply the exceptions and have the cost allocations in place prior to processing the annual cost adjustments for the 2009 production year. The expectation would be that industry uses this extended period of time to properly align their costs and volumes for the 2010 production year's annual cost reporting.

The set-up of new Facility Cost Centres (FCCs) for the purpose of assigning operating costs should be effective in the 2009 production year and onwards. Penalties associated with prior year FCC set-ups will not be waived.

If you have questions, please contact your respective Gas Royalty Client Services' portfolio representative, as identified in Section F of the Information Bulletin, or Will Wong at 780-415-0755 or e-mail Will.Wong@gov.ab.ca.

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry.

To contact the Petroleum Registry of Alberta Service Desk:
Phone: 403-297-6111 or 1-800-992-1144
Fax: 403-297-3665
Email: petroleumregistry.energy@gov.ab.ca

Alberta Energy Internet

Prices, Royalty Rates and Transportation Information are available on the Alberta Energy Internet address: www.energy.alberta.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Information Bulletins and Information Letters are also available under "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Services teams. Listed below is the portfolio breakdown along with Client Services Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at 780-644-1202.

Business Associate	Phone Number and E-mail Address	Team Lead
Numbered companies, A, B & L	780-644-1201 GRCST1@gov.ab.ca	Todd Atwood
C – G	780-644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	780-644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q – Z	780-644-1204 GRCST4@gov.ab.ca	Jyoti Bhambhani

Gas Royalty Reception:	780-422-8727
Fax:	780-427-3334 or 780-422-8732
Alberta Toll Free:	780-310-0000

Hours of operation are 8:15 a.m. to 4:30 p.m. Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer. Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas, you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas, you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone: 403-297-5514
Fax: 403-297-5400

Deen Khan
Director, Gas Royalty Operations
Royalty Operations

Attachments

2010 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butane ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	4.88	4.85	4.85	5.19	5.32	5.35	5.37
FEB	4.68	4.61	4.61	5.04	5.18	5.22	5.25
MAR	4.05	4.02	4.02	4.28	4.37	4.40	4.43
APR	3.26	3.22	3.22	3.60	3.71	3.73	3.75
MAY							
JUN							
JUL							
AUG							
SEPT							
OCT							
NOV							
DEC							

DETAIL OF THE APRIL 2010 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	3.625	3.601	3.764	3.820	3.823	3.834
Deductions: Intra – Alberta Transportation	0.302	0.321	0.184	0.129	0.099	0.075
Marketing Allowance	0.019	0.019	0.019	0.019	0.019	0.019
Price Before Pipeline Factor	3.304	3.261	3.561	3.672	3.705	3.740
Pipeline Fuel/Loss Factor	0.991	0.991	0.991	0.991	0.991	0.991
Price before Special Adjustment	3.274	3.233	3.531	3.640	3.673	3.707
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	3.274	3.233	3.531	3.640	3.673	3.707
Amendments: Carry forward (from previous RP month	-0.005	0.004	0.092	0.074	0.056	0.040
Prior Period Amendment Adjustment (current RP mon	-0.013	-0.014	-0.001	0.000	0.000	0.000
Calculated RP after Amendments	3.256	3.223	3.622	3.714	3.729	3.747
APRIL 2010 Reference Price	**3.26**	**3.22**	**3.60**	**3.71**	**3.73**	**3.75**
Difference = value carried forward to next RP month	-0.004	0.003	0.022	0.004	-0.001	-0.002
Adjusted IATD (before Prior Period Amendments)		0.319	0.182	0.128	0.099	0.075
Prior period Amendments (IATD and Pipeline Fuel Los		0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)		0.319	0.182	0.128	0.099	0.075

2010
NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Floor Price ($/m3)	Butane Reference Price ($/m3)	Butane Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	5.19	5.19	365.10	304.14	462.20	362.63	535.03	512.98	15.84
FEB	5.04	5.04	350.66	310.59	440.83	328.69	552.62	541.33	38.58
MAR	4.28	4.28	271.19	243.48	437.36	299.13	568.06	554.48	49.30
APR	3.60	3.60	269.23	242.05	428.49	308.22	583.58	574.41	69.93
MAY									
JUN									
JUL									
AUG									
SEPT									
OCT									
NOV									
DEC									

ANNUAL SULPHUR DEFAULT PRICE

2005	2006	2007	2008	2009
$33.97	$18.89	$32.88	$297.39	$6.35

2010

NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANE (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW. (per m3)
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	19.35	26.76	10.13	25.18	57.07	19.16	3.92	-10.19	57.95	52.54	63.03	51.40	17.25
FEB	8.52	17.16	-6.32	17.46	51.39	24.76	61.89	-8.43	51.58	51.62	55.86	45.56	17.25
MAR	10.32	18.62	1.65	17.28	51.24	32.88	15.96	5.15	59.67	47.42	53.64	47.86	17.25
APR	8.28	9.64	7.49	14.86	28.22	18.05	23.93	23.68	31.98	31.69	42.44	29.77	17.25
MAY													
JUN													
JUL													
AUG													
SEPT													
OCT													
NOV													
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butane obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

Note: For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS

NGL REFERENCE PRICES	APRIL 2010		
	Propane	*Butanes*	*Pentanes*
Price before amendments	269.230136	428.212167	582.463501
Opening Rollover (from prior business mth)	-0.001941	-0.003261	-0.000343
Prior Period Amendment Adj. (NGL-100)	0.000000	0.279943	1.113576
Published Reference Price	**269.23**	**428.49**	**583.58**

TRANSPORTATION ALLOWANCES	APRIL 2010											
	Pentanes Plus				Propane and Butane				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	0.000099	0.001796	0.004466	-0.003292	0.004191	-0.000301	0.004422	0.000063	-0.002996	0.001952	0.003724	0.003604
Prior Period Amendment Adj. (NGL-100)	1.113576	1.113576	1.113576	1.130876	0.164991	0.139084	0.250280	0.000000	0.173451	0.572870	0.632002	2.596913
Total Amendment Effect	1.113675	1.115372	1.118042	1.127584	0.169182	0.138783	0.254702	0.000063	0.170455	0.574822	0.635726	2.600517
Calculated Transp. Differential	7.162548	8.528037	6.368727	13.732685	28.052804	17.912778	23.675831	23.675831	31.813501	31.112379	41.800889	27.165566
Calculated Transp. Differential after Total Amendments	8.276223	9.643409	7.486769	14.860269	28.221986	18.051561	23.930533	23.675894	31.983956	31.687201	42.436615	29.766083
Published Transportation Allowance	**8.28**	**9.64**	**7.49**	**14.86**	**28.22**	**18.05**	**23.93**	**23.68**	**31.98**	**31.69**	**42.44**	**29.77**

Effective the January 2009 production period, the royalty rates for **methane** and **ethane** will be calculated based on a new royalty formula. The new royalty formula consists of the sum of a price component and a quantity component. The new royalty rates will range from 5% to 50%. **Propane** and **butanes** will have fixed royalty rates of 30%, whereas **pentanes plus** will have a fixed royalty rate of 40%.

The price component of the new royalty formula royalty rate for methane and ethane is determined by the monthly methane or ethane par price (PP)

Price ($/GJ)	r_p
PP ≤ 7.00	(PP – 4.50) * 0.0450
7.00 < PP ≤ 11.00	(PP – 7.00) * 0.0300 + 0.1125
PP > 11.00	(PP – 11.00) * 0.0100 + 0.2325
Maximum	30%
Minimum	Can be negative (-20.25% if PP=0)

The par price is a provincial weighted price determined by the department and published in the Information Letter for each production month. Determination of the par price has not changed under the Alberta Royalty Framework.

The quantity component of the new royalty formula royalty rate for methane and ethane is based on the average daily production (ADP) of the well event. The quantity component is adjusted for either the depth of the well event and/or the acid gas content of the well event.

Quantity ($10^3m^3/d$)	r_q
ADP≤ (6 * DF)	[ADP – (4 * DF)] * (0.0500/DF)
(6 * DF) < ADP ≤ (11* DF)	[ADP – (6 * DF)] * (0.0300/DF) + 0.1000
ADP > (11* DF)	[ADP – (11 * DF)] * (0.0100/DF) + 0.2500
Maximum	30%
Minimum	Can be negative

The ADP for a well event is the total raw gas production in thousand cubic metres (10^3m^3) for the month divided by the total hours of production in that month multiplied by 24. The ADP formula is as follows:

$$ADP = \frac{\text{Total raw gas production}}{\text{Total hours of production}} \times 24$$

Acid Gas Factor (AGF) is a factor that adjusts the ADP of a well event if that well event is producing high amounts of acid gas, that is, if the combined concentration of hydrogen sulphide (H2S) and carbon dioxide (CO_2) is greater than 3% and less than or equal to 25%. If a well event has an acid gas content of less than or equal to 3%, then the AGF of the well event will default to 1.00. If a well event has acid gas content greater than 25% then the AGF has a minimum value of 0.78.

The AGF is determined based on the following formula:

$$AGF = [1.03 – (H_2S\% + CO_2\%)]$$

The ADP is adjusted by multiplying the ADP by the AGF, that is:

Adjusted ADP = ADP * AGF

The acid gas content of a well event, used by the department for the determination of the AGF, will be according to the records of the ERCB.

A depth factor (DF) is required for all well events, and is calculated based on the measured depth (MD) according to the records of the ERCB for that well event. Information on the MD, of a well event, can be found on the Petroleum Registry of Alberta (PRA), in the 'Infrastructure' section.

The DF is used in the determination of the quantity component (r_q) of the royalty rate; it adjusts the quantity component royalty formula for measured depths that exceed 2000 metres. The DF for a well event is determined based on the following formula:

$$DF = \left(\frac{MD}{2000} \right)^2$$

A well event with a MD greater than 2,000 metres will receive a royalty adjustment based on production from the well event. A well event without a reported MD or with MD less than or equal to 2,000 metres will have a DF of 1.00. The DF is capped at 4.00 for well events with MD greater than or equal to 4,000 metres.

If the MD is

- $\leq$ 2,000 metres, then the DF = 1.00
- > 2,000 metres and <4,000 metres, then $DF = \left(\frac{MD}{2000} \right)^2$
- $\geq$ 4,000 metres, then the DF = 4.00